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UTILITIES COMMISSION

201 South Main, Suite 2300  
Salt Lake City, Utah 84111

January 31, 2014

**VIA OVERNIGHT DELIVERY**

Jean D. Jewell  
Commission Secretary  
Idaho Public Utilities Commission  
472 W. Washington  
Boise, ID 83702

**Re: Case No. PAC-E-14-01  
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER  
FOR AUTHORITY TO DECREASE RATES BY \$2.8 MILLION TO RECOVER  
DEFERRED NET POWER COSTS THROUGH THE ENERGY COST  
ADJUSTMENT MECHANISM**

Dear Ms. Jewell:

Please find enclosed an original and nine (9) copies of Rocky Mountain Power's Application in the above referenced matter, along with Rocky Mountain Power's direct testimony and exhibits. Also enclosed is a CD containing the Application, direct testimony, exhibits and confidential work papers.

All formal correspondence and questions regarding this Application should be addressed to:

Ted Weston  
Rocky Mountain Power  
201 South Main, Suite 2300  
Salt Lake City, Utah 84111  
Telephone: (801) 220-2963  
Fax: (801) 220-2798  
Email: [ted.weston@pacificorp.com](mailto:ted.weston@pacificorp.com)

Yvonne Hogle  
Rocky Mountain Power  
201 South Main Street, Suite 2300  
Salt Lake City, Utah 84111  
Telephone: (801) 220-4050  
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Email: [Yvonne.hogle@pacificorp.com](mailto:Yvonne.hogle@pacificorp.com)

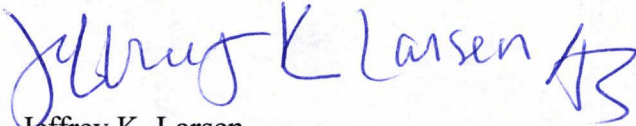
Communications regarding discovery matters, including data requests issued to Rocky Mountain Power, should be addressed to the following:

By E-mail (preferred): [datarequest@pacificorp.com](mailto:datarequest@pacificorp.com)

By regular mail:  
Data Request Response Center  
PacifiCorp  
825 NE Multnomah St., Suite 2000  
Portland, OR 97232

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

A handwritten signature in blue ink that reads "Jeffrey K. Larsen" followed by a stylized monogram or flourish.

Jeffrey K. Larsen  
Vice President, Regulation and Government Affairs

Enclosures

CC: Steven D. Spinner  
Randall C. Budge  
Brian Collins  
James R. Smith

R. Jeff Richards  
Yvonne R. Hogle (ISB# 8930)  
201 South Main Street, Suite 2300  
Salt Lake City, Utah 84111  
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E-mail: [yvonne.hogle@pacificorp.com](mailto:yvonne.hogle@pacificorp.com)

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UTILITIES COMMISSION

*Attorneys for Rocky Mountain Power*

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

**IN THE MATTER OF THE APPLICATION ) CASE NO. PAC-E-14-01  
OF ROCKY MOUNTAIN POWER FOR )  
AUTHORITY TO DECREASE RATES BY ) APPLICATION OF ROCKY  
\$2.8 MILLION TO RECOVER DEFERRED ) MOUNTAIN POWER  
NET POWER COSTS THROUGH THE )  
ENERGY COST ADJUSTMENT )  
MECHANISM )**

Rocky Mountain Power, a division of PacifiCorp (“Company” or “Rocky Mountain Power”), in accordance with Idaho Code §61-502, §61-503, and RP 052, hereby respectfully submits this application (“Application”) to the Idaho Public Utilities Commission (“Commission”) pursuant to the Company’s approved energy cost adjustment mechanism (“ECAM”). The Company is requesting approval of approximately \$12.8 million deferred net power costs from the deferral period beginning December 1, 2012 through November 30, 2013 (“Deferral Period”) and proposing to revise Electric Service Schedule No. 94, Energy Cost Adjustment, to recover approximately \$13.2 million in total deferred net power costs for the collection period beginning April 1, 2014 through March 31, 2015. The \$13.2 million includes an amortization from Monsanto’s and Agrium’s share of 2011, 2012 and 2013 deferrals, as further explained below. Recovery of this amount represents a decrease of approximately

\$2.8 million from Schedule 94 rates currently in effect as approved in Order No. 32771 in Case No. PAC-E-13-03. Monsanto's and Agrium's rates will increase while all other customers' rates will be reduced. Rocky Mountain Power respectfully requests that these changes to Idaho rate Schedule 94 become effective on April 1, 2014. In support of its Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Idaho, Wyoming, and Utah. Rocky Mountain Power is a public utility in the state of Idaho and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Idaho. Rocky Mountain Power is authorized to do business in the state of Idaho providing retail electric service to approximately 73,600 customers in the state.

2. Communications regarding this filing should be addressed to:

Ted Weston  
Idaho Regulatory Affairs Manager  
Rocky Mountain Power  
201 South Main, Suite 2300  
Salt Lake City, Utah 84111  
Telephone: (801) 220-2963  
Email: [ted.weston@pacificorp.com](mailto:ted.weston@pacificorp.com)

Yvonne R. Hogle, Senior Counsel  
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Salt Lake City, Utah 84111  
Telephone: (801) 220-4050  
Email: [yvonne.hogle@pacificorp.com](mailto:yvonne.hogle@pacificorp.com)

3. In addition, Rocky Mountain Power requests that all data requests regarding this Application be sent in Microsoft Word to the following:

By email (preferred): [datarequest@pacificorp.com](mailto:datarequest@pacificorp.com)

By regular mail: Data Request Response Center  
PacifiCorp  
825 Multnomah, Suite 2000  
Portland, Oregon 97232

Informal questions may be directed to Ted Weston, Idaho Regulatory Affairs Manager at (801) 220-2963.

### **ECAM Overview**

4. The ECAM became effective July 1, 2009, pursuant to an agreement among parties in Case No. PAC-E-08-08, as approved by the Commission September 29, 2009, in Order No. 30904. The ECAM allows the Company to collect or credit the difference between the actual net power costs (“NPC”) incurred to serve customers in Idaho and the NPC collected from Idaho customers through rates set in general rate cases.

5. The costs that are included in the ECAM are NPC as defined in the Company’s general rate cases and modeled by the Company’s production dispatch model GRID. Specifically, NPC include amounts booked to the following FERC accounts:

- Account 447 (sales for resale, excluding on-system wholesale sales and other revenues not modeled in GRID),
- Account 501 (fuel, steam generation, excluding fuel handling, start-up fuel/gas, diesel fuel, residual disposal and other costs not modeled in GRID),
- Account 503 (steam from other sources),
- Account 547 (fuel, other generation),
- Account 555 (purchased power, excluding BPA residential exchange credit pass-through if applicable), and
- Account 565 (transmission of electricity by others).

6. On a monthly basis, the Company compares the actual system net power costs ("Actual NPC") to the net power costs embedded in then effective rates ("Base NPC") from the general rate case during the Deferral Period and defers the difference into the ECAM balancing account. This comparison is on a system-wide, dollar per megawatt-hour basis.

7. In addition to the difference between Actual NPC and Base NPC, the ECAM includes five additional components: the Load Change Adjustment Revenues ("LCAR"), a credit for SO<sub>2</sub> allowance sales, an adjustment for load control costs, an adjustment for the treatment of coal stripping costs, i.e., Emerging Issues Task Force ("EITF") 04-6, and a true-up of 100 percent of the incremental Renewable Energy Credit ("REC") revenues from the amount approved by Commission Order No. 32196. These components are described in more detail below.

8. Finally, the ECAM includes a symmetrical sharing band of 90 percent (customers) / 10 percent (Company) that shares the differential between Actual NPC and Base NPC, LCAR, SO<sub>2</sub> sales, load control costs, and the coal stripping costs adjustment between the customers and the Company. The sharing band is also described in more detail below.

#### **Changes to ECAM Calculation**

9. In accordance with Commission Order 32910 in Case No. PAC-E-13-04, the Company has reflected changes to the ECAM calculation ordered by the Commission, as described in detail in Mr. Brian Dickman's Direct Testimony.

### **Proposed Deferred ECAM Rate Changes**

10. In support of this Application, Rocky Mountain Power has filed the testimony and exhibits of Company witnesses Brian Dickman and Joelle Steward. Mr. Dickman's testimony and exhibit describe the Actual NPC incurred by the Company to serve retail load for the historical twelve-month period ended November 30, 2013 and explain the main differences between Actual NPC and Base NPC. Ms. Steward's testimony supports the new ECAM tariff surcharge rates to be effective April 1, 2014 through March 31, 2015.

11. Commission Order No. 32432 from Case No. PAC-E-11-12 approved a stipulation entered into by parties in the Company's 2011 general rate case ("2011 GRC"), to amortize the 2013 ECAM deferral over two years for Monsanto and Agrium ("2011 GRC Stipulation"). The proposed rate change for Monsanto and Agrium in this case covers three ECAM deferral periods: 1) the third-year amortization of the 2011 ECAM deferral for the period of December 1, 2010 through November 30, 2011; 2) the second-year amortization of the 2012 ECAM deferral for the period of December 1, 2011 through November 30, 2012; and 3) the first-year amortization from the 2013 ECAM deferral for the period of December 1, 2012 through November 30, 2013. The 2011 GRC Stipulation specified that amounts owed by Monsanto and Agrium related to the Deferral Period in this case will be amortized over a two-year period. Monsanto's and Agrium's share of the deferral balance from this Deferral Period is approximately \$5.2 million and \$0.4 million, respectively. Thus, this filing includes the first-year of amortization of those amounts: approximately \$2.6 million for Monsanto and approximately \$0.2 million for Agrium. Combined, the amortization of the amounts from the three ECAM deferral

periods result in tariff surcharge rates in this case for Monsanto and Agrium in Schedule 94 of approximately \$6.0 million and \$0.5 million, respectively.

12. This Application is supported by Mr. Dickman's testimony and confidential Exhibit No. 1 ("Exhibit 1") which illustrates the detailed calculation of the ECAM deferral. During the Deferral Period, the Base NPC in rates originated from 2011 GRC which set Base NPC for calendar year 2012 at \$1.205 billion and for calendar year 2013 at \$1.385 billion. The combined Base NPC for the Deferral Period is \$1.369 billion.

13. The NPC deferral amount is calculated on a monthly basis by subtracting the monthly Base NPC rate from the Actual NPC rate. The NPC rate is calculated by dividing monthly NPC by the corresponding monthly load to express the costs on a dollar per megawatt-hour basis. On a dollar per megawatt-hour basis, the Base NPC average was \$23.47 per megawatt-hour, and the Actual NPC averaged \$26.02 per megawatt-hour, \$2.55 per megawatt-hour higher. The monthly incremental difference was multiplied by Idaho's actual load during the Deferral Period. Idaho's load is separated into three groups—tariff customers, Monsanto and Agrium—to calculate the deferral for each group. For the twelve-month period ended November 30, 2013, the NPC differential for deferral was approximately \$9.8 million before the 90/10 percent sharing band.

14. The LCAR is a symmetrical adjustment to offset over- or under-collection of the Company's energy-related production revenue requirement, excluding NPC, due to variances in Idaho load. The LCAR reduced the deferral balance by approximately \$1.1 million before sharing due to higher usage during the Deferral Period.

15. Revenues from SO<sub>2</sub> emission allowance sales received by the Company from December 1, 2012 to November 30, 2013 are also included as an offset to the NPC deferral. This adjustment reduces the deferral by approximately \$3,000 before sharing.

16. A fourth component of the ECAM tracks Idaho's share of incremental load control costs. Commission Order 32432 specified that the load control costs would be tracked in the ECAM. This adjustment reduces the deferral by \$0.2 million before sharing.

17. The fifth component of the ECAM is the difference between including coal stripping costs recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal stripping costs when the coal was excavated. This adjustment increases the deferral by approximately \$41,000 before sharing.

18. The total NPC deferral adjusted for LCAR, SO<sub>2</sub> revenue, load control, and EITF 04-6 is subject to the sharing band between customers and the Company such that customers pay/receive 90 percent of the increase/decrease in Actual NPC when compared to Base NPC, and the Company incurs/retains the remaining 10 percent.

19. In addition to the ECAM calculation components discussed above, the deferral balance reflects the difference between actual REC revenues during the Deferral Period and the amount of REC revenues included in base rates. The REC revenue true-up included in the ECAM is symmetrical but no sharing band is applied. During the Deferral Period actual REC revenue was approximately \$5.2 million lower than the amount in base rates on an Idaho-allocated basis.

20. The deferred ECAM balance of \$24.3 million as of November 30, 2013 is the sum of uncollected deferrals from prior ECAM filings plus the components described above for the Deferral Period: 90% X (deferred NPC + LCAR + SO<sub>2</sub> revenues + incremental load control + coal stripping costs adjustment) + the impact of the REC revenue true-up. Interest is accrued on the uncollected balance at the Commission-approved interest rate on customer deposits, currently 1 percent annually. Exhibit 1 illustrates the detailed calculations for tariff customers, with an ending balance of \$9.9 million; Monsanto, with an ending balance of \$13.4 million; and Agrium, with an ending balance of \$1.0 million.

**Allocation of Deferred ECAM Balance to Retail Tariffs**

21. Ms. Joelle Steward's testimony describes the calculation of the proposed Schedule 94 rates. Exhibit 2 of Ms. Steward's testimony illustrates this calculation based on metered loads, the line loss adjusted loads, the allocation of the ECAM price change, and the percentage change by rate schedule based on the present revenues ordered in Case No. PAC-E-13-04. Exhibit 3 is a clean and legislative copy of Electric Service Schedule No. 94 containing the proposed rates by electric service schedule based on the customer's delivery voltage of electric service.

22. Rocky Mountain Power is notifying its customers of this Application by means of a press release sent to local media organizations and messages in customers' bills over the course of a billing cycle. The customer bill inserts will begin on February 7, 2014, and continue through the twenty-one day billing cycle. Copies of the press release and bill insert are provided with the Application. In addition, copies of the

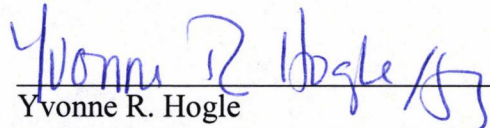
Application will be made available for review at the Company's local offices in its Idaho service territory.

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission (1) issue an order authorizing that this matter be processed by Modified Procedure; (2) approve the \$12.8 million ECAM deferral for the 2013 Deferral Period; and (3) implement the proposed Electric Service Schedule No. 94 as filed in Exhibit 3.

DATED this 31<sup>st</sup> day of January 2014.

Respectfully submitted,

ROCKY MOUNTAIN POWER



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*Attorney for Rocky Mountain Power*

For information contact: Media Hotline: 800-775-7950

Annual energy cost adjustment proposal

**Price reduction proposed for most customers**

BOISE, Idaho, Monday, Feb. 3, 2014—Rocky Mountain Power's annual energy cost adjustment for 2014 proposes to reduce prices for residential, commercial, and irrigation customers, with a modest increase for two large industrial customers.

The energy cost adjustment mechanism is designed to track the difference between the company's actual expenses for fuel and other costs to provide electricity to customers and the amount collected recently from customers through current prices. Pending commission approval, the adjustment would take effect April 1, 2014.

Under Rocky Mountain Power's proposal, all but two large industrial customers will see a reduction in their electric prices. The proposed adjustment will allow Rocky Mountain Power to continue to provide safe, reliable electric service to its customers.

The company's proposal requests that the Idaho Public Utilities Commission approve deferral of the 2013 energy related costs of \$12.8 million and reduce revenues collected through the energy cost adjustment mechanism, Schedule 94, by \$2.8 million.

The proposal would have the following impacts on prices:

- Residential customers – \$1.5 million decrease or 2.0 percent
- Commercial and most industrial customers – \$1.3 million decrease ranging from 2.1 percent to 3.2 percent, depending on the rate schedule
- Irrigation customers – \$1.5 million decrease or 2.4 percent
- Industrial customer, tariff Schedule 400 – \$1.4 million increase or 1.7 percent
- Industrial customer, Schedule 401 – \$0.1 million increase or 2.1 percent

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review at the commission offices in Boise and at the company's offices in Rexburg, Preston, Shelley and Montpelier.

Idaho Public Utilities Commission  
[www.puc.idaho.gov](http://www.puc.idaho.gov)  
472 W. Washington  
Boise, ID 83702

Rocky Mountain Power offices

- Rexburg – 25 East Main
- Preston – 509 S. 2nd East
- Shelley – 852 E. 1400 North

###

## **Annual energy cost adjustment proposal**

**Price reduction proposed  
for most customers**

### **Rocky Mountain Power requests recovery of power costs.**

On January 31, 2014, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve the 2013 deferral of \$12.8 million to the energy balancing account and adjust the energy cost adjustment rider down by \$2.8 million. Under Rocky Mountain Power's proposal all but two large industrial customers will see a reduction to their prices from this adjustment. The company is proposing to reduce all prices with the exception of tariff contract Schedules 400 and 401. The proposed adjustment will allow Rocky Mountain Power to continue to provide safe, reliable electric service to its customers.

The energy cost adjustment mechanism is designed to track the difference between the company's actual costs to provide electricity to Idaho customers and the amount collected from customers through current prices. Pending commission approval, the price change would take effect April 1, 2014.

The proposed price changes would have the following impacts:

- **Residential Schedule 1**  
1.9 percent decrease
- **Residential Schedule 36**  
2.3 percent decrease
- **General Service Schedule 6**  
2.6 percent decrease
- **General Service Schedule 9**  
3.2 percent decrease

*(continued)*

- **Irrigation Service Schedule 10**  
2.4 percent decrease
- **Comm & Ind. Heating Schedule 19**  
2.6 percent decrease
- **General Service Schedule 23**  
2.2 percent decrease
- **General Service Schedule 35**  
2.6 percent decrease
- **Public Street Lighting**  
1.0 percent decrease
- **Tariff Contract 400**  
1.7 percent increase
- **Tariff Contract 401**  
2.1 percent increase

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review at the commission offices in Boise and at the company's offices in Rexburg, Preston, Shelley and Montpelier.

**Idaho Public Utilities Commission**  
**472 W Washington**  
**Boise, ID 83702**  
[www.puc.idaho.gov/](http://www.puc.idaho.gov/)

**Rocky Mountain Power offices**

- Rexburg – 25 East Main
- Preston – 509 S. 2nd E.
- Shelley – 852 E. 1400 N.
- Montpelier – 24852 US Hwy 89

For more information about your prices and price schedule, go to [rockymountainpower.net/rates](http://rockymountainpower.net/rates).



**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

<b>IN THE MATTER OF THE APPLICATION</b>	)	<b>CASE NO. PAC-E-14-01</b>
<b>OF ROCKY MOUNTAIN POWER FOR</b>	)	
<b>AUTHORITY TO DECREASE RATES BY</b>	)	<b>DIRECT TESTIMONY OF</b>
<b>\$2.8 MILLION TO RECOVER DEFERRED</b>	)	<b>BRIAN S. DICKMAN</b>
<b>NET POWER COSTS THROUGH THE</b>	)	
<b>ENERGY COST ADJUSTMENT</b>	)	
<b>MECHANISM</b>	)	

**ROCKY MOUNTAIN POWER**

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**CASE NO. PAC-E-14-01**

**January 2014**

1 **Q. Please state your name, business address and present position with**  
2 **PacifiCorp, dba Rocky Mountain Power (the “Company”).**

3 A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street,  
4 Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

5 **Qualifications**

6 **Q. Briefly describe your education and business experience.**

7 A. I received a Master of Business Administration from the University of Utah with  
8 an emphasis in finance and a Bachelor of Science degree in accounting from Utah  
9 State University. Prior to joining the Company, I was employed as an analyst for  
10 Duke Energy Trading and Marketing. I have been employed by the Company  
11 since 2003 including positions in revenue requirement and regulatory affairs, and  
12 I assumed my current role managing the Company’s net power cost group in  
13 March 2012.

14 **Q. Have you testified in previous regulatory proceedings?**

15 A. Yes. I have filed testimony in proceedings before the public service commissions  
16 in California, Idaho, Oregon, Utah, and Wyoming.

17 **Summary of Testimony**

18 **Q. What is the purpose of your testimony in this proceeding?**

19 A. My testimony presents the Company’s calculation of the Energy Cost Adjustment  
20 Mechanism (“ECAM”) balancing account for the 12-month period from  
21 December 1, 2012 through November 30, 2013 (“Deferral Period”). More  
22 specifically, my testimony provides the following:

- 23
  - A summary of the ECAM calculation, including changes made to comply

1 with recent Commission orders.

- 2 • Details supporting the addition of \$12.8 million (“2013 Deferral”) to the
- 3 deferral balance, bringing the total balance of the account to \$24.3
- 4 million as of November 30, 2013.
- 5 • Additional details of the ECAM calculation and a description of the
- 6 Company’s net power costs (“NPC”).

7 **Q. Are additional witnesses presenting testimony in this case?**

8 A. Yes. Ms. Joelle R. Steward, Director, Pricing, Cost of Service & Regulatory  
9 Operations, is sponsoring testimony supporting the Company’s proposed ECAM  
10 collection rates in Schedule 94. The Company is proposing to modify electric  
11 service Schedule 94 effective April 1, 2014, so the Company would collect  
12 approximately \$13.2 million on an annual basis as compared to the current  
13 collection rate of approximately \$16.0 million.

14 **Summary of the ECAM Deferral Calculation**

15 **Q. Please briefly describe the Company’s ECAM authorized by the**  
16 **Commission.**

17 A. In general, the ECAM tracks deviations between actual NPC and the NPC in base  
18 rates and defers 90 percent of the difference for later recovery.<sup>1</sup> Other items, such  
19 as sales of sulfur dioxide (“SO<sub>2</sub>”) emission allowances or renewable energy  
20 credits (“RECs”), are also accounted for in the ECAM as a mechanism to true up  
21 to actual experience. The balance that accumulates over a deferral period is then  
22 passed on to customers as a rate surcharge or credit. The ECAM Schedule 94 rate,

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<sup>1</sup> Order No. 30904 in Case No. PAC-E-08-08 approved the stipulation entered into by the Commission Staff, the Idaho Irrigation Pumpers Association, Monsanto and the Company that set up the structure and content of the ECAM mechanism.

1 which appears as a separate line item on customer bills, collects or credits to  
2 customers the balance of deferred costs. Schedule 94 is adjusted as needed in the  
3 Company's annual ECAM filings. The annual deferral period for the ECAM is  
4 December 1 to November 30. The Company is required to file an application with  
5 the Commission by February 1 of each year to seek approval of the deferral  
6 amount and to adjust the ECAM rate effective April 1.

7 **Q. How are the 2013 ECAM deferral calculations presented in your testimony?**

8 A. The 2013 ECAM deferral calculations are contained in Exhibit No. 1. A summary  
9 of the major components is contained in Table 1 below. Later in my testimony I  
10 discuss the details of the calculations contained in Exhibit No. 1.

11 **Q. What changes to the ECAM calculation have been implemented to comply**  
12 **with Commission orders from previous cases?**

13 A. Consistent with the stipulation approved in Order No. 32910 in Case No. PAC-E-  
14 13-04, the Company has modified the ECAM calculation by removing the  
15 wholesale sales line loss adjustment from the calculation of Monsanto and  
16 Agrium's actual load for the calculation of all deferral balances except for the  
17 Load Change Adjustment Revenue ("LCAR"). This change applies from June 1,  
18 2013 to November 30, 2013. Starting December 1, 2013, the ECAM will be  
19 calculated on a total Idaho basis; Monsanto and Agrium's share will not be  
20 calculated separately.

21 The Company also updated the LCAR calculation by using the 2011 load  
22 reported in the Annual Result of Operations report as the base load for purposes of  
23 the ECAM deferral, consistent with the stipulation approved in Order No. 32432 in  
24 Case No. PAC-E-11-12 ("2011 Rate Case").

1           Beginning January 1, 2015, pursuant to the stipulation in Case No. PAC-  
2           E-13-04 the ECAM will include a resource adder to recover the investment in the  
3           new Lake Side II generation facility until it is reflected in rates as a component of  
4           rate base. The ECAM deferral will be based on the Lake Side II actual generation  
5           multiplied by \$1.99/MWh, and capped at a total of \$5.43 million or 2,729,500  
6           MWh. Lake Side II is currently expected to reach commercial operation by June  
7           2014.

8    **Incremental 2013 Deferral**

9    **Q.    Please describe the ECAM components that make up the 2013 Deferral.**

10   A.    The 2013 Deferral is the sum of customers' 90 percent share of the following  
11        items: the difference between the actual and in-rates NPC, the LCAR, the SO<sub>2</sub>  
12        allowance sales, the load control cost adjustment, and the Emerging Issues Task  
13        Force ("EITF") 04-6 coal cost adjustment. An additional true-up of 100 percent of  
14        the revenue difference from the sale of RECs is also included. Detailed  
15        calculations are provided in Exhibit No. 1 attached to my testimony, and Table 1  
16        below summarizes the various components making up the deferral.

**Table 1**  
**Summary of ECAM Deferral Account Balance**

	<u>Tariff</u>			<u>Total</u>
	<u>Customers</u>	<u>Monsanto</u>	<u>Agrium</u>	
NPC Differential for Deferral	5,784,623	3,714,394	292,377	9,791,394
LCAR	(925,283)	(264,254)	(3,987)	(1,193,524)
SO <sub>2</sub>	(1,655)	(1,310)	(113)	(3,078)
Load Control	(148,750)	(60,791)	(4,341)	(213,882)
EITF 04-6 Adjustment	38,852	1,737	41	40,631
	4,747,787	3,389,777	283,977	8,421,541
	90%	90%	90%	90%
Customer Responsibility	4,273,008	3,050,799	255,579	7,579,387
REC Deferral	2,961,681	2,105,280	163,432	5,230,394
<b>Total Company Recovery for NPC Deferral</b>	<b>7,234,690</b>	<b>5,156,080</b>	<b>419,011</b>	<b>12,809,781</b>
<b>Balancing Account Activity</b>				
Prior Deferral	14,033,226	11,850,355	845,421	26,729,003
ECAM Revenue Collection	(11,532,615)	(3,735,441)	(257,271)	(15,525,328)
Interest	123,431	130,941	9,683	264,055
<b>Activity Through November 30, 2013</b>	<b>2,624,042</b>	<b>8,245,855</b>	<b>597,833</b>	<b>11,467,730</b>
<b>November 30, 2013 Balance For Collection</b>	<b>9,858,732</b>	<b>13,401,935</b>	<b>1,016,844</b>	<b>24,277,511</b>
Schedule 94 Collection - Dec 2013 - March 2014	(3,071,315)	(1,500,049)	(114,688)	(4,686,052)
<b>Expected Balance as of April 1, 2014</b>	<b>6,787,416</b>	<b>11,901,886</b>	<b>902,156</b>	<b>19,591,459</b>
Schedule 94 Collection - April 2014 - March 2015	(6,787,416)	(5,950,943)	(451,078)	(13,189,438)
<b>Expected Balance as of April 1, 2015 (Excluding 2014 Deferral)</b>	<b>-</b>	<b>5,950,943</b>	<b>451,078</b>	<b>6,402,021</b>
<b>Monsanto/Agrium Amortization</b>				
2012 ECAM Balance (2011 Deferral) - 3 Yr Amortization		2,261,074	156,424	2,417,498
2013 ECAM Balance (2012 Deferral) - 3 Yr Amortization		2,115,024	154,418	2,269,442
2014 ECAM Balance (2013 Deferral) - 2 Yr Amortization		2,578,040	209,506	2,787,546

- 1    **Q.     Please explain the calculation of the ECAM balance for the Deferral Period.**
- 2    A.     Table 1 above summarizes the components of the ECAM balance, broken into
- 3           three customer groups. The first section summarizes the Idaho-allocated share of
- 4           those items for which Idaho customers and the Company share responsibility:
- 5           NPC differential, LCAR, SO<sub>2</sub> sales, load control costs, and the EITF 04-6
- 6           adjustment. The next section calculates the 90 percent customer share of the
- 7           above items and adds in the Idaho-allocated REC revenue true-up, for which
- 8           customers are refunded or surcharged 100 percent of the difference. The total of

1 these items constitutes the 2013 Deferral. The 2013 Deferral of \$12.8 million is  
2 primarily a result of the \$8.8 million customers' share of the NPC differential and  
3 the \$5.2 million REC revenue differential. The increase in these components is  
4 partially offset by the \$1.1 million credit for the customers' share of the LCAR  
5 adjustment.

6 The next section, Balancing Account Activity, starts with the \$26.7  
7 million balance in the ECAM deferral account as approved in Order No. 32597.  
8 That balance is adjusted for collections and interest accrued during the Deferral  
9 Period. When the 2013 Deferral is added, the total outstanding balance as of  
10 November 30, 2013 is \$24.3 million. The final rows in Table 1 illustrate the  
11 expected Schedule 94 collections between December 1, 2013, and March 31,  
12 2014, and then over the next collection period from April 1, 2014, to March 31,  
13 2015. Finally, the table shows the annual amount that would need to be collected  
14 from Monsanto and Agrium according to the multi-year amortization schedules  
15 agreed to in the settlement agreement approved by the Commission in the 2011  
16 Rate Case.

17 **Q. Based on your calculations, what is the balance expected to be in the ECAM**  
18 **deferral account as of April 1, 2014?**

19 A. As of April 1, 2014, there will be an estimated balance of \$19.6 million due for  
20 collection—Monsanto is responsible for \$11.9 million, Agrium is responsible for  
21 \$0.9 million, and the remaining \$6.8 million will be due from other retail  
22 customers.

1 **Q. What is the proposed collection amount due from customers under Schedule**  
2 **94 beginning April 1, 2014?**

3 A. As discussed by Company witness Ms. Steward, the Company proposes to collect  
4 \$6.8 million from retail tariff customers beginning April 1, 2014. The surcharge  
5 rate for Monsanto and Agrium will be set at approximately \$6.4 million,  
6 combined, to reflect the multiple amortization periods outlined in the 2011 Rate  
7 Case stipulation. Ms. Steward's testimony details the rate impact of the updated  
8 ECAM collections.

9 **Q. The stipulation in the 2011 Rate Case stated the Company would track in the**  
10 **ECAM Idaho's share of the customer load control service credit for the**  
11 **irrigation load control program. Have you included an adjustment to true up**  
12 **these expenses?**

13 A. Yes. The Company has included a reduction of \$213,882, prior to the 90 / 10  
14 sharing, as an adjustment to true up the Idaho allocated load control service costs.  
15 This reduction to the ECAM deferral calculation can be seen on line 40 of Exhibit  
16 No. 1.

17 **Summary of the NPC Differences**

18 **Q. Please explain the difference between adjusted actual NPC ("Actual NPC")**  
19 **and the NPC in base rates ("Base NPC").**

20 A. On a total Company basis, Actual NPC for the Deferral Period were  
21 approximately \$1.569 billion. During the Deferral Period, the Base NPC in rates  
22 originated from the 2011 Rate Case. The stipulation approved in that case  
23 established Base NPC for 2012 and 2013. Base NPC for 2012 were set at \$1.205

1 billion and the Base NPC for 2013 were set at \$1.385 billion. The combined Base  
2 NPC for the Deferral Period is \$1.369 billion.

3 **Q. Did the Company anticipate that the actual NPC would be higher than the**  
4 **NPC included in rates during the Deferral Period?**

5 A. Yes. Mr. J. Ted Weston's testimony supporting the stipulation in the 2011 Rate  
6 Case described that increasing NPC was a significant driver of the overall rate  
7 increase sought in that case. He explained that the stipulation in 2011 Rate Case  
8 spread the known increase in NPC over a period of two years in order to mitigate  
9 the rate impact of the rate case.<sup>2</sup> Mr. Weston cited that as of November 2011 the  
10 Company expected actual NPC to be \$1.35 billion in 2011 and over \$1.5 billion in  
11 2012. Actual NPC were \$1.39 billion for 2011 and \$1.50 billion in 2012. He also  
12 stated, "Ultimately, 90 percent of the difference between actual net power costs  
13 and in-rates net power costs will be deferred and collected in the ECAM,  
14 customers get the benefit of the delay in paying the higher level until the costs  
15 become "actual" and also benefit from 10 percent of the incremental difference  
16 not being included in the ECAM deferral."

17 In June 2013 the Company reached an agreement with multiple parties in  
18 Case No. PAC-E-13-04 establishing an alternative rate plan in lieu of filing  
19 another general rate case. Mr. Weston's testimony filed in support of that  
20 stipulation indicated that the rates currently in effect justified a price increase,  
21 primarily driven by three factors: higher actual net power costs, lower REC  
22 revenues, and increased depreciation expense.<sup>3</sup> These first two items are the main

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<sup>2</sup> Case No. PAC-E-11-12, Testimony of J. Ted Weston at 7-8.

<sup>3</sup> Case No. PAC-E-13-04, Stipulation Testimony of J. Ted Weston at 3-4.

1 drivers of the difference in costs in the Deferral Period. Mr. Weston explained that  
2 the potential to recover increased actual NPC and lower REC revenue through the  
3 ECAM enabled the Company to delay the rate case anticipated in 2013 and to enter  
4 into the alternative rate plan.<sup>4</sup>

5 **Q. Did parties to the stipulation understand the impact these settlements would**  
6 **have on the ECAM?**

7 A. Yes. As noted by Mr. Weston the parties supported this approach knowing they  
8 would benefit from the delay in paying the higher level of net power costs.

9 **Q. Has the Company provided quarterly ECAM reports as directed by the**  
10 **Commission in Case No. PAC-E-12-03?**

11 A. Yes. The Company has provided preliminary ECAM calculations on a quarterly  
12 basis to enable ongoing analysis of the ECAM. The last quarterly report, provided  
13 for the period December 2012 through August 2013, projected an incremental  
14 deferral of \$10.3 million through August 2013. The final ECAM calculation  
15 provided in Exhibit No. 1 calculates a \$10.1 million deferral for the same period.

16 **Q. What are the major drivers that result in a difference between Actual NPC**  
17 **and Base NPC?**

18 A. The \$200 million difference on a total company basis between the combined Base  
19 NPC and Actual NPC in the Deferral Period is summarized in Table 2 by major  
20 category in the NPC report.

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<sup>4</sup> Case No. PAC-E-13-04, Stipulation Testimony of J. Ted Weston at 9-10.

**Table 2**  
**Deferral Period NPC Reconciliation (\$ millions)**

<b>Base NPC</b>	<b>\$1,369</b>
<b>Increase/(Decrease) to NPC:</b>	
Wholesale Sales Revenue	403
Purchased Power Expense	(154)
Coal Fuel Expense	74
Natural Gas Expense	(59)
Wheeling, Hydro and Other Expenses	(7)
<b>Total Increase/(Decrease)</b>	<b>\$257</b>
<b>Settlement Adjustment</b>	<b>(57)</b>
<b>Adjusted Actual NPC</b>	<b>\$1,569</b>

An apples-to-apples comparison of Base NPC and Actual NPC is difficult due to the disparity in timing between the test period used to determine Base NPC in the 2011 Rate Case and the period over which those rates have been in effect. Base NPC were set using a calendar year 2011 test period and the settlement in that case included a “black box” adjustment to determine Base NPC in rates during 2012 and 2013.

**Q. Notwithstanding the issues you describe above, can you explain some of the differences in NPC categories?**

A. Yes. The major contributor to the variance in NPC is a reduction in wholesale sales revenue. The increase in NPC due to lower wholesale sales and higher coal fuel expense is partially offset by reduced purchased power and natural gas fuel expenses. Higher load and lower hydro generation also contributed to higher costs compared to Base NPC.

**Q. Please explain the reduction in wholesale sales revenue.**

A. The reduction in wholesale sales revenue is driven by the expiration of four long-

1 term sales contracts and reduced revenue from wholesale market sales. Wholesale  
2 sales contracts with Nevada Power, Pacific Gas and Electric, Public Service  
3 Company of Colorado, and Southern California Edison were included in Base  
4 NPC but expired prior to the end of the Deferral Period. This accounted for a \$66  
5 million reduction in wholesale sales revenue and a 1.9 million MWh reduction in  
6 sales volume.

7 Revenue from market transactions (represented in GRID as short-term  
8 firm and system balancing sales) is approximately \$339 million lower than Base  
9 NPC. The drop in revenue is due primarily to a reduction in the average price of  
10 market sales transactions. Market sales transactions in the 2011 Rate Case were  
11 included at an average price of \$52.43/MWh, while actual market sales during the  
12 Deferral Period were done at an average price of \$29.36/MWh.

13 **Q. Please explain the reduction in purchased power expense.**

14 A. Similar to wholesale sales, the reduction in purchased power expense is driven by  
15 the expiration of several long-term contracts and reduced expenses from  
16 wholesale market purchases. Long term contracts expiring prior to the end of the  
17 Deferral Period include purchases from Grant County Public Utility District  
18 ("PUD"), Chelan County PUD, and Roseburg Forest Products; a Kennecott  
19 generation incentive; two call options with Morgan Stanley; and a peaking  
20 contract with the Bonneville Power Administration. The expiration of these  
21 contracts accounts for an approximately \$70 million reduction in purchased power  
22 expense. In addition, expenses related to several qualifying facility ("QF")  
23 contracts were reduced approximately \$46 million due to the customers utilizing

1 the QF generation to serve their own load.

2 Expenses from market transactions (represented in GRID as short-term  
3 firm and system balancing purchases) are approximately \$102 million lower than  
4 Base NPC. The drop in expenses is due mainly to reduced volume of market  
5 purchases, partially offset by an increase in the average price of market purchase  
6 transactions.

7 **Q. Are there any new long term purchase contracts that partially offset the**  
8 **overall reduction in purchased power expense?**

9 A. Yes. There are four new wind qualifying facilities in Idaho that had little or no  
10 generation in Base NPC, increasing purchased power expense approximately \$26  
11 million. These include the Power County North and South QFs which came  
12 online at the end of 2011, and the Five Pine and North Point QFs which came  
13 online at the end of 2012. In addition, during the Deferral Period the Company  
14 purchased the output of the West Valley generating station under a tolling  
15 agreement.

16 **Q. Please explain the change in natural gas and coal fuel expense.**

17 A. Natural gas market prices were approximately 15 percent lower in the Deferral  
18 Period compared to the prices assumed in the Base NPC. Lower market prices  
19 contributed to an increase in natural gas generation volume of 1,910 GWh (32  
20 percent), but the increase in generation volume is more than offset by a reduction  
21 in the total cost per MWh of natural gas generation. Coal generation volume  
22 increased by 1,721 GWh (four percent) contributing to an overall increase of \$74  
23 million in coal fuel expense. The average cost of coal generation increased from

1           \$16.60/MWh in Base NPC to \$17.64/MWh in the Deferral Period.

2   **Q.    How did changes in load and hydro generation impact NPC?**

3   A.    Actual system load during the deferral period was 2,071 GWh (four percent)  
4           higher than the load in Base NPC, and hydro generation in the Deferral Period  
5           was 608 GWh (15 percent) lower than in Base NPC. Higher load and lower hydro  
6           generation contribute to the reduced wholesale sales revenue and increased  
7           purchased power expenses shown in Table 2.

8   **Description of the ECAM Calculations**

9   **Q.    Please describe the ECAM calculations in Exhibit No. 1.**

10  A.    The ECAM deferral is calculated by comparing the Actual NPC to the Base NPC  
11           on a monthly basis and deferring the differences into an ECAM balancing  
12           account. The deferral amount is the difference in the system dollar per megawatt-  
13           hour rate multiplied by the Idaho retail load. Exhibit No. 1 details the ECAM  
14           calculation and contains supporting information, portions of which are  
15           confidential.

16  **Q.    How are the Base NPC and Actual NPC dollar per megawatt-hour rates**  
17           **calculated?**

18  A.    The monthly NPC for Base NPC in the Deferral Period are divided by the  
19           corresponding monthly normalized load to express the costs on a dollar per  
20           megawatt-hour basis (Exhibit No. 1, line 1). The Actual NPC rate on a dollar per  
21           megawatt-hour basis is calculated by dividing the monthly Actual NPC by the  
22           actual monthly system load (Exhibit No. 1, line 8). On a dollar per megawatt-hour  
23           basis, the Base NPC average is \$23.47 per megawatt-hour, and the Actual NPC

1 averaged \$26.02 per megawatt-hour, \$2.55 per megawatt-hour higher.

2 **Q. Please describe how the NPC deferral is calculated.**

3 A. The deferral is calculated on a monthly basis by subtracting the Base NPC rate  
4 from the Actual NPC rate. The resulting monthly NPC rate differential (Exhibit  
5 No. 1, line 9) is then multiplied by three groups of actual Idaho retail load at  
6 input: tariff customers, Monsanto, and Agrium (Exhibit No. 1, lines 10 through  
7 12) to calculate the NPC differential for deferral for each customer group,  
8 (Exhibit No. 1, lines 14 through 16). For the 12-month period ended November  
9 2013 the NPC differential was approximately \$9.8 million before application of  
10 the 90 / 10 sharing.

11 **Q. What costs are included in the NPC differential for deferral?**

12 A. The NPC differential for deferral captures all components of NPC as defined in  
13 the Company's general rate case proceedings and modeled by the Company's  
14 production dispatch model ("GRID"). Specifically, Base NPC and Actual NPC  
15 include amounts booked to the following Federal Energy Regulatory Commission  
16 ("FERC") accounts:

17 Account 447 – Sales for resale, excluding on-system wholesale sales and  
18 other revenues that are not modeled in GRID

19 Account 501 – Fuel, steam generation; excluding fuel handling, start-up  
20 fuel (gas and diesel fuel, residual disposal) and other costs  
21 that are not modeled in GRID

22 Account 503 – Steam from other sources

23 Account 547 – Fuel, other generation

1 Account 555 – Purchased power, excluding the Bonneville Power  
2 Administration (“BPA”) residential exchange credit pass-  
3 through if applicable

4 Account 565 – Transmission of electricity by others

5 **Q. Are adjustments made to the Actual NPC prior to comparing to Base NPC?**

6 A. Yes. The Actual NPC recorded on the Company’s books are adjusted to remove  
7 entries that are not included in the determination of the Company’s Base NPC for  
8 regulatory purposes, such as out of period accounting entries. In addition, Actual  
9 NPC adjustments are applied to reflect prior Commission approved adjustments,  
10 such as the revenue imputation of the sales contract with the Sacramento  
11 Municipal Utility District and removal of the effect of special contract customers  
12 buying through curtailment.

13 **Q. What constitutes an out of period accounting entry?**

14 A. Out of period accounting entries are items booked during the Deferral Period but  
15 that pertain to an operating period prior to the inception of the ECAM on July 1,  
16 2009.

17 **Q. Why is the cutoff of July 1, 2009, used to demarcate out of period entries?**

18 A. Since the ECAM took effect, customers’ rates have been adjusted to recover  
19 essentially all of the Company’s actual net power costs, excluding any differences  
20 due to the 90 / 10 sharing. As a result, any accounting entries made during the  
21 current Deferral Period that relate to any operating period since the ECAM took  
22 effect should also be reflected in customer rates, whether they increase or  
23 decrease Actual NPC. Accounting entries related to operating periods prior to the

1 inception of the ECAM should not impact the ECAM deferral.

2 **Q. In addition to the comparison of Actual NPC to Base NPC, what other**  
3 **components are included in the ECAM?**

4 A. There are five additional components included in the ECAM calculations: (i) the  
5 LCAR adjustment (ii) a credit for any SO<sub>2</sub> allowance sales, (iii) a true-up of load  
6 control costs, (iv) an adjustment for deferred costs associated with coal mine  
7 stripping activities recorded under the Financial Accounting Standards Board  
8 ("FASB") EITF 04-6, and (v) a true-up of REC revenues as authorized by the  
9 Commission in Order No. 32196.

10 **Q. Please describe the LCAR adjustment.**

11 A. The calculation of the LCAR adjustment is a symmetrical adjustment for over- or  
12 under-collection of the energy-related portion of the Company's embedded  
13 revenue requirement for production facilities as specified in Case No. GNR-E-10-  
14 03, Order No. 32206. The LCAR accounts for variances in Idaho load that cause  
15 the Company to collect more or less of these production-related costs. The LCAR  
16 rate was last set in Order No. 32432 at \$5.47 per megawatt-hour. This rate has  
17 been in effect since April 1, 2011.

18 **Q. How is the LCAR adjustment calculated and what is the impact on the 2013**  
19 **Deferral?**

20 A. The LCAR adjustment is calculated by subtracting the Idaho load at input  
21 established in rates ("Base Load" shown in Exhibit No. 1, lines 18 through 20),  
22 from actual Idaho load at input ("Actual Load" shown in Exhibit No. 1, lines 22  
23 through 24). The difference (Exhibit No. 1, lines 26 through 28) is then multiplied

1 by the LCAR of \$5.47 per megawatt-hour in all months of the Deferral Period  
2 (Exhibit No. 1, line 30) to arrive at the LCAR adjustment (Exhibit No. 1, lines 31  
3 through 33) of (\$1,193,524) before the 90 / 10 sharing.

4 **Q. How are SO<sub>2</sub> sales revenues included in the ECAM?**

5 A. Line 35 of Exhibit No. 1 contains the SO<sub>2</sub> sales revenue during the Deferral  
6 Period on a total Company basis. Line 37 of Exhibit No. 1 is Idaho's allocated  
7 share of the SO<sub>2</sub> sales revenue which is calculated using Idaho's System Energy  
8 ("SE") allocation factor authorized by the Commission from the 2011 Rate Case.  
9 For the Deferral Period, the total SO<sub>2</sub> sales revenue credit is a \$3,078 reduction to  
10 the NPC deferral balance before the 90 / 10 sharing.

11 **Q. How is the adjustment for load control costs calculated in the ECAM?**

12 A. The load control cost adjustment is a comparison of actual costs for load control  
13 programs compared to the base level established in the 2011 Rate Case. The  
14 stipulation approved in the 2011 Rate Case established the base amount to be  
15 tracked in the ECAM as \$1,045,423. Idaho-allocated actual load control costs  
16 during the Deferral Period were approximately \$831,540. The difference, shown  
17 on line 40 of Exhibit No. 1, is included as a \$213,882 reduction to the NPC  
18 deferral balance before the 90 / 10 sharing.

19 **Q. How is the adjustment for accounting pronouncement EITF 04-6 included in**  
20 **the ECAM?**

21 A. Line 41 of Exhibit No. 1 reflects Idaho's allocated differences between the coal  
22 stripping costs incurred by the Company and recorded on the Company's books  
23 pursuant to the guidance of the accounting pronouncement EITF 04-6, and the

1 amortization of the coal stripping costs when the coal was excavated. For the  
2 Deferral Period, the total EITF 04-6 coal stripping deferral adjustment is a  
3 \$40,631 increase to the NPC deferral balance before the 90 / 10 sharing.

4 **Q. Please explain the sharing ratio between the Company and customers in the**  
5 **ECAM.**

6 A. The ECAM includes a symmetrical sharing ratio in which customers either pay or  
7 receive 90 percent of the ECAM deferral balance and the Company is responsible  
8 for the remaining 10 percent. Lines 55 through 58 of Exhibit No. 1 represent the  
9 customers' 90 percent share of the monthly deferral shown on lines 50 through 53  
10 of Exhibit No. 1. For the Deferral Period, the customers' share of the deferred  
11 balance is approximately \$7.6 million. The remaining balance of approximately  
12 \$0.8 million is not included in the deferral calculation and is not recoverable from  
13 customers.

14 **Q. What is the amount of REC revenue true-up in the current filing?**

15 A. As authorized by the Commission in Case No. PAC-E-10-07, Order No. 32196,  
16 the Company included the difference between actual REC revenues during the  
17 Deferral Period and the amount of REC revenues included in base rates. The REC  
18 revenue true-up included in the ECAM is symmetrical but no sharing band is  
19 applied – the entire difference between base and actual REC revenues is either  
20 refunded or surcharged to customers. Base rates during the Deferral Period  
21 included \$6.5 million in Idaho-allocated REC revenue. Idaho's actual REC  
22 revenues for that same time period were approximately \$1.3 million, a difference  
23 of \$5.2 million (Exhibit No. 1, line 61).

1 **Q. What is the total ECAM deferred balance as calculated in Exhibit No. 1?**

2 A. The total ECAM deferred balance as of November 30, 2013 is \$24.3 million,  
3 shown on line 88 of Exhibit No. 1.

4 **Q. How is this balance divided among customers?**

5 A. The ECAM deferral is divided into three customer groups based on each group's  
6 actual load during the deferral period. Of the \$24.3 million, \$9.9 million is  
7 allocated to the tariff customers (Exhibit No. 1, Line 73), \$13.4 million to  
8 Monsanto (Exhibit No. 1, Line 80) and \$1.0 million to Agrium (Exhibit No. 1,  
9 Line 87). The Company will amortize and collect Monsanto's and Agrium's share  
10 of the Commission-approved 2013 Deferral over two years pursuant to the  
11 stipulation in the 2011 Rate Case. Beginning December 1, 2013, future ECAM  
12 deferrals will be calculated on total company basis; Monsanto's and Agrium's  
13 share will not be divided out and deferred separately. However, the existing  
14 balances will continue to be identified separately and included in rates for  
15 Monsanto, Agrium, and remaining tariff customers until fully recovered.

16 **Q. Does the calculation of the deferred NPC adjustment in this application**  
17 **comply with the parameters of the Idaho ECAM as approved by the**  
18 **Commission?**

19 A. Yes.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.

**CONFIDENTIAL**

Case No. PAC-E-14-01

Exhibit No. 1

Witness: Brian S. Dickman

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

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**CONFIDENTIAL**

Exhibit Accompanying Direct Testimony of Brian S. Dickman

January 2014

**THIS EXHIBIT IS CONFIDENTIAL  
AND IS PROVIDED UNDER  
SEPARATE COVER**

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

<b>IN THE MATTER OF THE APPLICATION</b>	)	<b>CASE NO. PAC-E-14-01</b>
<b>OF ROCKY MOUNTAIN POWER FOR</b>	)	
<b>AUTHORITY TO DECREASE RATES BY</b>	)	<b>DIRECT TESTIMONY OF</b>
<b>\$2.8 MILLION TO RECOVER DEFERRED</b>	)	<b>JOELLE R. STEWARD</b>
<b>NET POWER COSTS THROUGH THE</b>	)	
<b>ENERGY COST ADJUSTMENT</b>	)	
<b>MECHANISM</b>	)	

**ROCKY MOUNTAIN POWER**

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**CASE NO. PAC-E-14-01**

**January 2014**

1 **Q. Please state your name, business address and present position with**  
2 **PacifiCorp, dba Rocky Mountain Power (“the Company”).**

3 A. My name is Joelle R. Steward. My business address is 825 NE Multnomah Street,  
4 Suite 2000, Portland, Oregon 97232. My present position is Director of Pricing,  
5 Cost of Service, and Regulatory Operations in the Regulation Department.

6 **Qualifications**

7 **Q. Briefly describe your education and business experience.**

8 A. I have a B.A. degree in Political Science from the University of Oregon and an  
9 M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at the  
10 University of Minnesota. Between 1999 and March 2007, I was employed as a  
11 Regulatory Analyst with the Washington Utilities and Transportation  
12 Commission. I joined the Company in March 2007 as Regulatory Manager,  
13 responsible for all regulatory filings and proceedings in Oregon. I assumed my  
14 current position in February 2012.

15 **Q. Have you appeared as a witness in previous regulatory proceedings?**

16 A. Yes. I have testified in regulatory proceedings in Idaho, Oregon, Utah,  
17 Washington and Wyoming.

18 **Q. What is the purpose of your testimony in this proceeding?**

19 A. I support the Company’s proposed rates in this case.

20 **Background**

21 **Q. What level of revenues is Schedule 94, Energy Cost Adjustment, currently**  
22 **designed to collect?**

23 A. Schedule 94 is designed to collect approximately \$16.0 million—\$4.5 million for

1 Tariff Contract 400, \$0.3 million for Tariff Contract 401, and \$11.1 million for  
2 the standard tariff customers—based on Idaho loads from Case No. PAC-E-13-04.

3 **Proposed Rate Change for Schedule 94**

4 **Q. Please describe Rocky Mountain Power's proposed rate change in this case.**

5 A. In this 2014 Energy Cost Adjustment Mechanism ("ECAM") filing, the Company  
6 proposes to change its current ECAM surcharge collection rates. For Tariff  
7 Contracts 400 and 401, the Company proposes to increase the tariff surcharge  
8 rates in Tariff Schedule 94 with a collection rate of approximately \$6.0 million  
9 and \$0.5 million, respectively, on an annual basis from April 1, 2014 to March 31,  
10 2015. For standard tariff customers, the Company proposes to decrease the tariff  
11 surcharge rates in Tariff Schedule 94 with a collection rate of approximately \$6.8  
12 million on an annual basis from April 1, 2014 to March 31, 2015.

13 **Q. Why is the Company proposing to decrease the ECAM collection rates for**  
14 **standard tariff customers?**

15 A. Based on 2012 loads and the present rates authorized in Case No. PAC-E-13-04  
16 the Company projects that the annual revenue collected from Schedule 94  
17 surcharge for standard tariff customers would be approximately \$11.1 million,  
18 about \$4.3 million more than the \$6.8 million projected ECAM balance as of  
19 March 31, 2014, as supported in Table 1 in Mr. Brian S. Dickman's testimony,  
20 filed concurrently with mine. Therefore, the Company proposes to decrease  
21 Schedule 94 rates for these customers to collect approximately \$6.8 million.

22 **Q. Please explain the proposed rate change for Tariff Contracts 400 and 401.**

23 A. In the Company's 2011 general rate case, Case No. PAC-E-11-12, the parties

1 stipulated and Commission Order No. 32432 approved a plan to phase-in the rate  
2 impact from the 2011, 2012, and 2013 ECAM deferrals for these tariff contracts.  
3 The proposed rate change for Tariff Contracts 400 and 401 covers the  
4 amortization for the three ECAM deferral periods: The first deferral period is for  
5 the 2011 ECAM deferral period of December 1, 2010 through November 30,  
6 2011. This deferral is being amortized over three years. This filing includes the  
7 third year of amortization for that deferral—\$2.4 million for Tariff Contract 400  
8 and \$0.2 million for Tariff Contract 401.

9 The second deferral period is for the 2012 ECAM deferral period of  
10 December 1, 2011 through November 30, 2012, and is also being amortized over  
11 three years. This filing includes the second year of amortization for that  
12 deferral—\$2.1 million for Tariff Contract 400 and \$0.1 million for Tariff Contract  
13 401.

14 The third is for the 2013 ECAM deferral period of December 1, 2012  
15 through November 30, 2013. As supported in Mr. Dickman's testimony, Tariff  
16 Contract 400 is responsible for \$5.2 million and Tariff Contract 401 is responsible  
17 for \$0.4 million. Commission Order No. 32432 approved amortization of the 2013  
18 ECAM deferral amounts over two years. Therefore, this filing includes \$2.6  
19 million for Tariff Contract 400 and \$0.2 million for Tariff Contract 401, which is  
20 one-half of their total applicable 2013 ECAM deferral amounts.

21 The combined amortization of the three ECAM deferral periods for Tariff  
22 Contracts 400 and 401 equal approximately \$6.0 million and \$0.5 million,  
23 respectively on an annual basis. Schedule 94 surcharge rates have been designed

1 to collect these annual amounts from these customers. The Company will track  
2 the recovery of the three different deferral period amounts by proportioning the  
3 collections consistent with each contract customers' annual amortization balance.  
4 For example, Tariff Contract 400's 2011 ECAM deferral amortization amount is  
5 30.2 percent of the total collection target of \$6.0 million, so 30.2 percent of the  
6 collections from Schedule 94 from April 1, 2014 to March 31, 2015, will be  
7 applied against the 2011 ECAM deferral balance.

8 **Q. What is the impact from the above ECAM rate change proposals?**

9 A. As summarized in my Exhibit No. 2, these rate change proposals result in a 1.7  
10 percent increase for Tariff Contract 400, a 2.1 percent increase for Tariff Contract  
11 401 and a 2.3 percent decrease for standard tariff customers.

12 **Proposed Rates for Schedule 94**

13 **Q. How were the proposed Schedule 94 rates developed for Tariff Contract 400**  
14 **and Tariff Contract 401?**

15 A. The proposed rates for these two customers were developed by dividing their total  
16 collection targets identified above with their 2012 kWh consumption at the  
17 transmission voltage level. This results in the proposed Schedule 94 rates of 0.425  
18 cents per kWh for Tariff Contract 400, and 0.423 cents per kWh for Tariff  
19 Contract 401.

20 **Q. How were the proposed Schedule 94 rates developed for standard tariff**  
21 **customers?**

22 A. The proposed rates for standard tariff customers were developed in three steps.  
23 First, their kWh consumption at the generation level was developed by multiplying

1        their retail loads at the delivery service voltage level with the corresponding line  
2        loss factors. Next, an overall average rate at the generation level was developed by  
3        dividing their total collection target identified above with their kWh consumption  
4        at the generation level. Last, the proposed rates by delivery voltage level were  
5        developed by multiplying the above overall average rate at the generation level  
6        with the corresponding line loss factors. As the result, the Company proposes  
7        Schedule 94 rates of 0.348, 0.336 and 0.327 cents per kWh for secondary, primary  
8        and transmission delivery service voltages, respectively, for standard tariff  
9        customers.

10    **Q.     Please describe Exhibit No. 2.**

11    A.     Exhibit No. 2 illustrates the 2012 metered loads, the line loss adjusted loads, the  
12        allocation of the ECAM price change, and the percentage change by rate schedule  
13        based on the ordered revenues from Case No. PAC-E-13-04.

14    **Q.     Please describe Exhibit No. 3.**

15    A.     Exhibit No. 3 contains clean and legislative copies of the proposed Electric Service  
16        Schedule No. 94, Energy Cost Adjustment, designed to collect approximately  
17        \$13.2 million of the ECAM deferred balance. Consistent with the ECAM, the  
18        Company proposes the new rates become effective April 1, 2014.

19    **Q.     Does this conclude your testimony?**

20    A.     Yes.

Case No. PAC-E-14-01  
Exhibit No. 2  
Witness: Joelle R. Steward

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Joelle R. Steward

January 2014

**EXHIBIT 2**  
**ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT**  
**FROM ELECTRIC SALES TO ULTIMATE CONSUMERS**  
**DISTRIBUTED BY RATE SCHEDULES IN IDAHO**  
**HISTORIC 12 MONTHS ENDED DECEMBER 2012**

Line No.	Description (1)	Sch. (2)	Average		Present		At Meter			At		ECAM Proposal				Present		Net Change														
			Cust (3)	MWH (4)	Rev (\$000) (5)	MWh by Voltage			Generation MWh <sup>1</sup> (9)	Rev (\$000) (10)	Rate ¢/kWh <sup>2</sup>			ECAM Rev (\$000) <sup>3</sup> (14)	Net Change (\$000) (15)	% (16)																
						S (6)	P (7)	T (8)			S (11)	P (12)	T (13)																			
<b>Residential Sales</b>																																
1	Residential Service	1	43,685	424,866	\$46,305	424,866			467,981	\$1,479	0.348	0.336	0.327	\$2,417						-\$939	-1.9%											
2	Residential Optional TOD	36	14,279	260,612	\$24,053	260,612			287,059	\$907	0.348	0.336	0.327	\$1,483						-\$576	-2.3%											
3	AGA Revenue				\$3																											
4	Total Residential		57,964	685,477	\$70,361	685,477	0	0	755,040	\$2,386				\$3,900						-\$1,515	-2.0%											
<b>Commercial &amp; Industrial</b>																																
5	General Service - Large Power	6	1,048	281,899	\$21,796	235,944	45,956		308,818	\$976	0.348	0.336	0.327	\$1,595						-\$620	-2.6%											
6	General Svc. - Lg. Power (R&F)	6A	219	32,396	\$2,739	32,396			35,683	\$113	0.348	0.336	0.327	\$184						-\$72	-2.4%											
7	Subtotal-Schedule 6		1,267	314,295	\$24,535	268,339	45,956	0	344,501	\$1,088				\$1,780						-\$691	-2.6%											
8	General Service - High Voltage	9	15	118,837	\$7,145			118,837	123,122	\$389	0.348	0.336	0.327	\$636						-\$247	-3.2%											
9	Irrigation	10	4,894	658,325	\$56,316	658,325			725,131	\$2,291	0.348	0.336	0.327	\$3,746						-\$1,455	-2.4%											
10	Comm. & Ind. Space Heating	19	116	8,559	\$672	8,559			9,428	\$30	0.348	0.336	0.327	\$49						-\$19	-2.6%											
11	General Service	23	6,841	145,173	\$13,776	143,798	1,376		159,855	\$505	0.348	0.336	0.327	\$826						-\$321	-2.2%											
12	General Service (R&F)	23A	1,823	24,281	\$2,413	24,281			26,745	\$85	0.348	0.336	0.327	\$138						-\$54	-2.1%											
13	Subtotal-Schedule 23		8,664	169,454	\$16,189	168,079	1,376	0	186,600	\$590				\$964						-\$374	-2.2%											
14	General Service Optional TOD	35	3	1,144	\$91	1,144			1,260	\$4	0.348	0.336	0.327	\$7						-\$3	-2.6%											
15	Contract 1 <sup>4</sup>	400	1	1,400,114	\$78,233			1,400,114	1,450,588	\$5,951			0.425	\$4,536						\$1,415	1.7%											
16	Contract 2 <sup>4</sup>	401	1	106,646	\$5,923			106,646	110,491	\$451			0.423	\$321						\$130	2.1%											
17	AGA Revenue				\$599																											
18	Total Commercial & Industrial		14,961	2,777,374	\$189,703	1,104,445	47,331	1,625,597	2,951,120	\$10,794				\$12,038						-\$1,244	-0.6%											
<b>Public Street Lighting</b>																																
20	Security Area Lighting	7	194	256	\$96	256			282	\$1	0.348	0.336	0.327	\$1						-\$1	-0.6%											
21	Security Area Lighting (R&F)	7A	134	108	\$44	108			119	\$0	0.348	0.336	0.327	\$1						-\$0	-0.5%											
22	Street Lighting - Company	11	30	71	\$31	71			78	\$0	0.348	0.336	0.327	\$0						-\$0	-0.5%											
23	Street Lighting - Customer	12	276	2,444	\$429	2,444			2,691	\$9	0.348	0.336	0.327	\$14						-\$5	-1.2%											
24	AGA Revenue				\$0																											
25	Total Public Street Lighting		634	2,878	\$600	2,878	0	0	3,170	\$10				\$16						-\$6	-1.0%											
26	Total Sales to Ultimate Customers		73,559	3,465,729	\$260,664	1,792,800	47,331	1,625,597	3,709,330	\$13,189				\$15,955						-\$2,765	-1.0%											
27	Total (Excluding Sch 400, 401)		73,557	1,958,969	\$176,509	1,792,800	47,331	118,837	2,148,251	\$6,787				\$11,097						-\$4,310	-2.3%											
28																			Present													
29	<sup>1</sup> Equal to MWh sales by voltage times the corresponding loss factors in this line:																		Present													
30	<sup>2</sup> Total Proposed ECAM Revenue (\$000) and Rate by Voltage (cents/kWh):																		0.324	<	Sch 400											
31	<sup>3</sup> Equal to MWh sales by voltage times the corresponding present rate in this line:																		0.301	<	Sch 401											

Case No. PAC-E-14-01  
Exhibit No. 3  
Witness: Joelle R. Steward

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Joelle R. Steward

January 2014

I.P.U.C. No. 1

**Fourth Revision of Sheet No. 94.1**  
**Cancelling Third Revision of Sheet No. 94.1**

**ROCKY MOUNTAIN POWER**  
**ELECTRIC SERVICE SCHEDULE NO. 94**

**STATE OF IDAHO**

**Energy Cost Adjustment**

**AVAILABILITY:** At any point on the Company's interconnected system.

**APPLICATION:** This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

**ENERGY COST ADJUSTMENT:** The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

**MONTHLY BILL:** In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		<u>Delivery Voltage</u>		
		<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>
Schedule	1	0.348¢ per kWh		
Schedule	6	0.348¢ per kWh	0.336¢ per kWh	
Schedule	6A	0.348¢ per kWh	0.336¢ per kWh	
Schedule	7	0.348¢ per kWh		
Schedule	7A	0.348¢ per kWh		
Schedule	9			0.327¢ per kWh
Schedule	10	0.348¢ per kWh		
Schedule	11	0.348¢ per kWh		
Schedule	12	0.348¢ per kWh		
Schedule	19	0.348¢ per kWh		
Schedule	23	0.348¢ per kWh	0.336¢ per kWh	
Schedule	23A	0.348¢ per kWh	0.336¢ per kWh	
Schedule	24	0.348¢ per kWh	0.336¢ per kWh	
Schedule	35	0.348¢ per kWh	0.336¢ per kWh	
Schedule	35A	0.348¢ per kWh	0.336¢ per kWh	
Schedule	36	0.348¢ per kWh		
Schedule	400			0.425¢ per kWh
Schedule	401			0.423¢ per kWh

Submitted Under Case No. PAC-E-14-01

**ISSUED:** January 31, 2014

**EFFECTIVE:** April 1, 2014

I.P.U.C. No. 1

~~Third-Fourth~~ Revision of Sheet No. 94.1  
Cancelling ~~Second-Third~~ Revision of Sheet No. 94.1

**ROCKY MOUNTAIN POWER**  
**ELECTRIC SERVICE SCHEDULE NO. 94**

**STATE OF IDAHO**

**Energy Cost Adjustment**

**AVAILABILITY:** At any point on the Company's interconnected system.

**APPLICATION:** This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

**ENERGY COST ADJUSTMENT:** The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

**MONTHLY BILL:** In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	<del>0.3480.569</del> ¢ per kWh		
Schedule	6	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	6A	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	7	<del>0.3480.569</del> ¢ per kWh		
Schedule	7A	<del>0.3480.569</del> ¢ per kWh		
Schedule	9			<del>0.535327</del> ¢ per kWh
Schedule	10	<del>0.3480.569</del> ¢ per kWh		
Schedule	11	<del>0.3480.569</del> ¢ per kWh		
Schedule	12	<del>0.3480.569</del> ¢ per kWh		
Schedule	19	<del>0.3480.569</del> ¢ per kWh		
Schedule	23	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	23A	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	24	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	35	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	35A	<del>0.3480.569</del> ¢ per kWh	<del>0.3360.550</del> ¢ per kWh	
Schedule	36	<del>0.3480.569</del> ¢ per kWh		
Schedule	400			<del>0.324425</del> ¢ per kWh
Schedule	401			<del>0.301423</del> ¢ per kWh

Submitted Under Case No. PAC-E-~~14-0113-03~~

ISSUED: ~~January 31~~~~March 28, 2013~~2014

EFFECTIVE: April 1, 201~~4~~3